ABBREVIATED VERSION OF THE DRAFT STATUS REPORT CONCERNING THE ASSESSMENT OF GRID OPERATING DATA FOR SIGNS OF CHANGE AND POTENTIAL VULNERABILITIES

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ABSTRACT

This report provides the status of an assessment, conducted by the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research (RES), of operating data concerning the Nation's electrical power grid. The grid is the "offsite power system" and the "preferred source" of alternating current (ac) electric power for the safety loads at the Nation's nuclear power plants (NPPs). The purpose of this assessment is to review the available grid-related operating data for indications of change, emerging trends, or potential vulnerabilities[1] that might otherwise be masked by investigating only the operating data for the NPPs themselves.

On August 14, 2003, large regions of the U.S. and Canada experienced a widespread power grid outage (blackout), which caused nine U.S. NPPs to trip. That blackout and its consequences reinforced the RES staff's earlier observations regarding changes in the performance of the grid, as reported in NUREG-1784, "Operating Experience Assessment: Effects of Grid Events on Nuclear Power Plant Performance," dated December 2003[2]. Consequently, RES proposed, and the NRC's Office of Nuclear Reactor Regulation supported, an assessment to determine whether the observed changes in grid performance are a transient or permanent condition. This assessment of grid reliability based on performance trends developed from approximately 600 grid events from 1984 through 2003 and 7,000 transmission records from 1997 through 2004. In particular, the assessment develops indices and insights to gauge the impact of changes in transmission system loading and grid reliability.

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1 Potential vulnerabilities are sensitive information that have been deleted from this version of the report.

2 This work was completed prior to the blackout on August 14, 2003.

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EXECUTIVE SUMMARY

This report provides the status of an assessment, conducted by the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research (RES), of operating data concerning the Nation's electrical power grid. The grid is the "offsite power system" and the "preferred source" of alternating current (ac) electric power for the safety loads at the Nation's nuclear power plants (NPPs). The purpose of this assessment is to review the available grid-related operating data for indications of change, emerging trends, or potential vulnerabilities[1] that might otherwise be masked by investigating only the operating data for the NPPs themselves. The NRC staff will then use the results to assess whether the agency needs to reevaluate the effectiveness of its existing regulatory documents and protective features, as they relate to the sources of electrical power for NPPs. The results of this assessment will also indicate whether the NRC needs to revisit the assumptions about the grid in its risk analyses.

The "grid" and "NPP offsite power system" refer to the same system of generators that produce power that is then transmitted over a system of transmission lines for subsequent distribution to customers or loads. The NPPs are connected to the grid as a generator and as a load, and are subject to the same conditions that affect the grid. The NPPs neither operate nor maintain the grid, and the NRC has no jurisdiction over the grid.

On August 14, 2003, large regions of the United States and Canada, experienced a widespread power grid outage (blackout), which caused nine U.S. NPPs to trip. Those plants remained disconnected from the grid for a considerable period, and eight of the nine NPPs experienced losses of offsite power (LOOPs). That blackout and its consequences reinforced the RES staff's earlier observations regarding changes in the performance of the grid, as they related to LOOPs.[2] Currently, there is uncertainty whether the observed changes in grid performance are a transient or permanent condition. Consequently, RES proposed, and the NRC's Office of Nuclear Reactor Regulation supported, an assessment of variations in grid data.

In addition to the NRC's own assessments, the U.S. Secretary of Energy and the Canadian Minister of Natural Resources established a Power System Outage Task Force to evaluate the blackout and determine its root cause. The task force's "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," dated April 5, 2004, states that with the absence of major transmission projects of the past 10–15 years, utilities have increased their utilization of the existing transmission facilities to meet increasing demands without adding major equipment. This report revealed changed conditions that challenge grid reliability; applied the work of experts who treat the grid as a "complex system" to show that this blackout was a rare, but predictable, high-consequence event; and stated that "If nothing else changed, one could expect an increased frequency of large-scale events as compared to historical experience." NPP risks are dominated by rare, high-consequence events, and an increase in the frequency of large-scale events can increase the risk at multiple NPPs simultaneously.

The NRC has routinely analyzed grid reliability based solely on NPP LOOP data, and has not investigated other grid-related operating data. The grid data may be relevant once the data similarities are recognized (e.g., an NPP LOOP is a blackout), and using the grid data to better understand grid blackout characteristics may provide additional insights for NRC consideration. By contrast, the

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North American Electric Reliability Council (NERC) defines grid reliability in terms of the "adequacy" of the generation supply and the "operating reliability" of the generating and transmission systems to cope with contingencies such as a blackout. Given that definition, NERC completes an annual high-level forecast of grid reliability based on self-assessments; plans for new facilities; and the potential effects of changes in market forces, legislation, regulation, and other factors. The NERC data include several blackouts that differ from the NPP station blackout (SBO) scenario, which is a complete loss of both offsite and onsite ac electric power to the NPP.

This assessment of grid reliability is based on performance trends developed from the NERC data, including 600 grid events from 1984 through 2003 and 7,000 transmission line load relief records from 1997 through 2004. In so doing, the staff classified the 600 grid events using the NERC definitions for adequacy, operating reliability, or unusual events. The staff then used the data to provide reliability measures to gauge recent changes in grid operation. An assessment (such as this) that is based on a large amount of data should promote confidence in the results. The results obtained to date indicate changes and vulnerabilities that have the potential to adversely impact NPP voltages and risks. In fact, since 1999, transmission system congestion has increased and the Nation has experienced an increased number of larger and longer-lasting grid blackouts than the previous 15 years. In addition, results obtained to date indicate that both the grid and the NPPs' offsite power supply are complex systems, and grid-related events created conditions in which power took a long time to restore. The following paragraphs elaborate on the most notable findings obtained to date:

(1) Transmission system congestion (overloading) is increasing as a result of normal load growth, open generator access to the transmission system as a result of deregulation of the electric industry, and limited transmission system construction over the past 15–20 years. NERC anticipated transmission line congestion and created a transmission load relief (TLR) request procedure to manage the congestion. The TLR request logs show that the transmission system has become increasingly congested each year from 1999 through 2004. The data also show that the transmission system is more congested at some times than at others and more congested on some days than on others (mostly from August through October). The data may also indicate potential bottlenecks or problem areas. Experience shows that transmission line congestion near an NPP degrades the plant's operating voltages and may result in a LOOP in the event of a reactor trip. As a next step, it appears that sufficient data are now available to determine the percentage of time during which the grid is in a degraded condition under which an NPP reactor trip will result in a LOOP.

(2) The NERC data indicate changes in grid reliability. Adequacy improvement over the 15 years prior to 1999 has been offset by the decline in grid performance from 1999 through 2003. Operating reliability was less from 1999 through 2003 than it was in the preceding 15 years. Specifically, since 1999, the number, median size, and median duration of blackouts have increased, and the largest blackouts (those that are larger than 800 megawatts and last more than 4 hours) are both larger and of longer duration than the largest blackouts that occurred before 1999. Thus, it appears that pushing the transmission system harder has diminished the grid's capability to withstand contingencies. In addition, the NRC's current risk assessments (which typically average NPP LOOP data from the past 15–20 years) may mask vital information; the data since 1999 may reflect true grid performance and challenge the NRC assumptions that use grid data before 1999.

(3) This assessment supports the findings of experts in chaos theory and non-linear system dynamics, which indicate that the grid is a complex system. Complex systems behave such that a small disturbance alters the system to the point of chaos because of the interplay between the system components. The characteristic curve of a complex system is described by power laws (i.e., a straight line slope, commonly referred to as a power tail) when the cumulative frequency (or probabilities) of blackout size is equal to or greater than a given size when plotted on a log-log scale. The experts showed that the grid data are described by power laws. The NPP LOOP data yield a more pronounced power tail than the grid data, indicating that the NPP offsite power system tends to be is a complex system. This is significant because the methods used to describe complex systems differ from those that the NRC currently uses to assess NPP risks relative to grid performance and, consequently, application of complex system techniques may yield different results and risk insights.

As a next step, the RES staff plans to obtain electrical engineering comments, continue analyzing grid data, and issue an interim report for appropriate internal and external stakeholder review. As RES moves forward, these findings may require the NRC staff to reevaluate the effectiveness of the agency's existing regulatory documents and protective features (as they relate to the sources of electrical power for NPPs), and/or revisit the assumptions about the grid in its risk analyses.

ABBREVIATIONS

ac	alternating current
BOR	"Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations."
CFR	*Code of Federal Regulations*
DAWG	Disturbance Analyses Working Group
dc	direct current
DOE	Department of Energy (U.S.)
EDG	emergency diesel generator
EEIB	Electrical Engineering and Instrumentation Branch (NRR)
FERC	Federal Energy Regulatory Commission
GDC	General Design Criterion
ISO	independent system operator
kV	kilovolt
LER	licensee event report
LOOP	loss of offsite power
MVAR	megavolt-ampere-reactive
MW	megawatt
NEPA	National Energy Policy Act of 1992
NERC	North American Electric Reliability Council
NPP	nuclear power plant
NRC	Nuclear Regulatory Commission (U.S.)
NRR	Nuclear Reactor Regulation, Office of (NRC)
RC	reliability coordinator
RES	Nuclear Regulatory Research, Office of (NRC)
RTO	reliability transmission organization
SBO	station blackout
SCADA	supervisory control and data acquisition
TLR	transmission load relief

1. INTRODUCTION

This report provides the status of an assessment, conducted by the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research (RES), of operating data concerning the Nation's electrical power grid. The grid is the "offsite power system" and the "preferred source" of alternating current (ac) electric power for the safety loads at the Nation's nuclear power plants (NPPs). The purpose of this assessment is to review the available grid-related operating data for indications of change, emerging trends, or potential vulnerabilities[1] that might otherwise be masked by investigating only the operating data for the NPPs themselves. The issue is whether the grid has changed to the point that the NRC might need to reevaluate the effectiveness of its existing regulatory documents and protective features, as they relate to the sources of electrical power for NPPs, and whether the NRC should revisit the assumptions about the grid in its risk analyses.

The "grid" and "NPP offsite power system" refer to the same system of generators that produce power that is then transmitted over a system of transmission lines for subsequent distribution to customers or loads. The NPPs are connected to the grid as both generators and loads and, as such, they are subject to the same conditions that affect the grid.

On August 14, 2003, large regions of the United States and Canada, experienced a widespread power grid outage (blackout), which caused nine U.S. NPPs to trip. Those plants remained disconnected from the grid for a considerable period, and eight of the nine NPPs experienced losses of offsite power (LOOPs). That blackout and its consequences reinforced the RES staff's earlier observations regarding changes in the performance of the grid, as they related to LOOPs in NUREG-1784, "Operating Experience Assessment: Effects of Grid Events on Nuclear Power Plant Performance,"[2] dated December 2003 (Ref. 1). Currently, there is uncertainty whether the observed changes in grid performance are a transient or permanent condition. Consequently, RES proposed, and the NRC's Office of Nuclear Reactor Regulation (NRR) supported, an assessment of variations in grid data.

In addition to the NRC's own assessments, the U.S. Secretary of Energy and the Canadian Minister of Natural Resources, established a Power System Outage Task Force that prepared the "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," (BOR) dated April 5, 2004 (Ref. 2), to evaluate the root cause of the August 14, 2003 blackout and recommend actions to prevent another major blackout. The task force also evaluated history experience and stated that with the absence of major transmission projects of the past 10–15 years, utilities have increased their utilization of the existing transmission facilities to meet increasing demands without adding major equipment. This report revealed changed conditions that challenge grid reliability; applied the work of experts who treat the grid as a "complex system" to show that this blackout was a rare, but predictable, high-consequence event; and stated that "If nothing else changed, one could expect an increased frequency of large-scale events as compared to historical experience." NPP risks are dominated by rare, high-consequence events, and an increase in the frequency of large-scale events can increase the risk at multiple NPPs simultaneously.

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2 This work was completed prior to the blackout on August 14, 2003.

The NRC has routinely analyzed grid reliability based solely on NPP LOOP data, and has not investigated other grid-related operating data. This assessment of grid reliability based on performance trends developed from the NERC data, including 600 grid events from 1984 through 2003 and 7,000 transmission line load relief records from 1997 through 2004. The rationale was that by using this broad data set, RES might be able to identify grid performance changes or vulnerabilities that are masked by analyzing NPP data alone. Toward that end, RES used the NERC data to provide reliability measures to gauge recent changes in grid operation. Specific objectives of the current RES assessment are to obtain sufficient grid data to identify and assess the following considerations: (1)transmission system loading near NPPs, (2) grid reliability, (3) the percent of the time the grid is degraded such that a reactor trip will result in a LOOP, (4) whether the data indicate that the NPP offsite power supply is a complex system, and (5) vulnerabilities that are potential risk-significant issues for the NPPs

The NRC staff planned this assessment in three steps:

(1) As a first step, RES had to obtain reliable and representative grid data. Collaboration with the industry revealed that the NERC data set was best suited to our assessment. After discussing our plans with NERC and the Electrical Engineering and Instrumentation Branch (EEIB) of the NRR Division of Engineering, RES decided to begin by investigating various aspects of grid reliability and transmission loading, which would then be summarized in a draft report for electrical engineering review by NERC and EEIB before RES proceeded with more detailed analyses.

(2) As a second step RES planned to identify and assess the variations in grid performance that have the potential to impact NPP performance or risk, and estimate the percentage of time during which the grid is degraded such that a reactor trip will result in a LOOP. As part of the second step, RES expected to obtain additional data and information through collaboration with the industry. To conclude this step, RES planned to document its findings in an interim report to solicit comments from appropriate internal and external stakeholders.

(3) The final step will involve developing a report that addresses the stakeholder comments on the interim report, and provides the basis for a Commission decision on whether the NRC should reevaluate the effectiveness of its existing electrical regulations and other regulatory documents and protective features, as they relate to the sources of electrical power for NPPs. The results of this assessment will also indicate whether the NRC needs to validate the assumptions used in risk analyses of the reliability of the Nation's electrical power grid.

As an overview, Section 2 of this report provides background information needed to understand assessment. Section 3, "Discussion," then discusses the assessment to date and the resultant observations (shown in italics), while Section 4, "Assessment," integrates those observations into a cohesive assessment of the grid data, as augmented by data in Appendices A and B. Finally, Section 5 lists the related references cited throughout this report.

2. BACKGROUND

2.1 Description of the Grid or the Nuclear Power Plant Offsite Power System

The “grid” or “NPP offsite power system” is typically the “preferred source” of ac electric power for all NPP operating conditions (including accident and post-accident conditions). The NRC’s regulations use the term “offsite power system” interchangeably with the electric industry terms “grid,” “electric power system,” or “bulk power system.” The safety function of the offsite power system is to provide power to the ac safety loads that are required to shut down the NPP, including loads in the decay heat removal system that are required to preserve the integrity of the reactor core and containment following a reactor trip. The NPPs do not operate or maintain the grid, and the NRC has no jurisdiction over the grid. However, LOOPs often dominate the NPP risks, and the reliability of the generation supply and the transmission system are important to the NPP.

The NPPs also have redundant, onsite emergency ac power supplies [typically emergency diesel generators (EDGs)] that automatically start and connect to the safety loads following a LOOP. To the grid, a LOOP is the loss of one large customer and, therefore, is considered a blackout. The NPPs are capable of withstanding a *station blackout* (SBO), which is a complete loss of ac electric power to the NPP (i.e., a LOOP concurrent with a turbine trip and unavailability of the emergency ac power system) and, as such, is different from a *grid blackout* which is a loss of customers or load. The NPPs also have redundant, onsite emergency direct current (dc) power supplies, which consist of batteries and chargers that provide control power for safety equipment. During an SBO event, the NPP relies heavily on dc batteries to cope for a specified duration (coping time) and recover from the SBO event.

Functionally, the North American electric power grid consists of three large and nearly independent synchronous electric circuits. These are the Eastern, Western, and ERCOT Interconnections, which are shown in Figure 1, “Interconnections in the North American Grid” (Ref. 1).

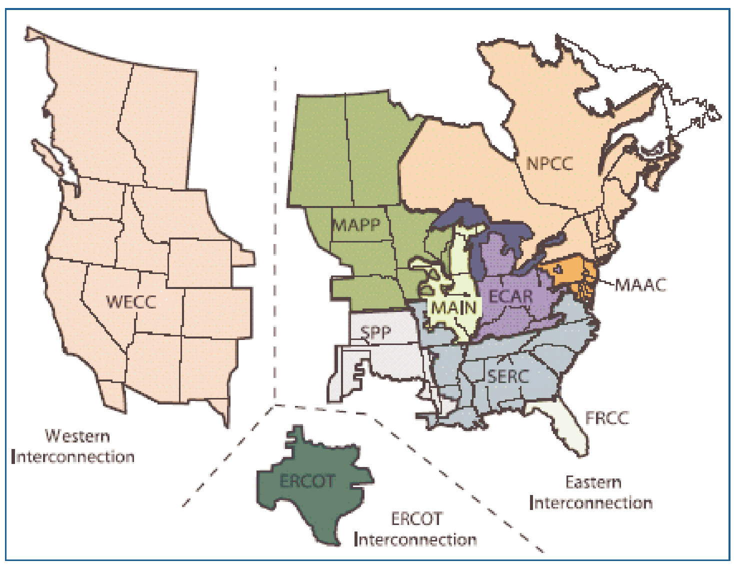


Figure 1 – Interconnections in the North American Grid

The terms “grid” and “NPP offsite power system” both refer to the same system of generators (including the NPP generators) that produce power, which is then stepped up to high voltages to transmit large amounts of power efficiently over a system of transmission lines. The power is then stepped down to lower voltages at substations for distribution to customers (including the NPP house loads). The transmission system is usually designated by the highest voltage levels on that portion of the grid [typically 115–765 kilovolts (kV)], and there is often a sub-transmission network that operates at voltages between those of the distribution and transmission systems.

Typically, each NPP is supplied by two or more physically independent transmission lines; thus, the NPPs are connected to the grid as both generators and loads and, as such, they are subject to the same conditions that affect the grid. The transmission lines, in turn, are interconnected at switchyards to form a redundant network of parallel paths that ensure uninterruptible transfer of power to customers during an outage or following a disturbance. The transmission network also serves as a path to spread major disturbances. Current flows freely in the parallel paths of the transmission network according to the fundamental (Kirchoff's) laws of electricity. That is, the current flows in the paths of least resistance and does not always take the obvious path. For example, when power is transmitted from Ontario to New York via the 765-kV system, some of it goes through Michigan, Ohio, and Virginia, as well directly from Ontario to New York.

The grid is very robust because it is designed and operated within limits that allow for multiple transmission and or generating system outages and has the capability to withstand a disturbance, or other contingency, without interrupting power. When equipment is removed from service, the remaining operating equipment assumes the burden to produce and or transmit more power within current, voltage, or frequency limits. Nonetheless, analysis is required to predict the amount and path of the current and power, as well as the resulting voltages, to ensure satisfactory operation for the conditions being experienced. Failure to analyze the grid to support changing operating conditions and make the appropriate adjustments can result in abnormal current, voltages or frequencies. These abnormalities can cause widespread equipment problems, including a loss performance, operation of multiple protective devices, damage, and irrecoverable failures. Such abnormalities can also result in system voltage collapse and potential long-term problems, such as premature failures from aging.

2.2 Grid Reliability as Defined by the North American Electric Reliability Council

NERC defines grid reliability in terms of the "adequacy" of the generation system to supply demand (that is, the rate at which the load is using energy) and the "security" or (more recently) "operating reliability" of the transmission system to cope with contingencies. Specifically, NERC uses the following definitions of grid reliability (Ref. 3):

- **Adequacy** is the ability of the electric system to supply aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Operating reliability** is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated losses of system elements (such as a reactor trip or loss of a transmission line).

2.3 Operating Responsibilities and Activities for Grid Reliability

NERC is a consensus-based industry organization that has developed operating and planning standards to control grid reliability; however, the implementation of those standards is voluntary at this time. NERC has 10 regional councils, as shown in Figure 2, "NERC Regions and Control Areas" (Ref. 3). NERC compiles high-level forecasts of grid reliability based on regional council self-assessments; plans for new facilities; and potential effects of changes in market forces, legislation, regulation, and other factors. NERC forecasts may identify opportunities for improvement, areas needing attention, or the need to monitor. Typical assumptions in the NERC forecasts are that the weather will be normal, generating and transmission equipment will perform at average availability levels, outages will follow schedules, demand reductions will be effective, and electric transfers will occur as projected.

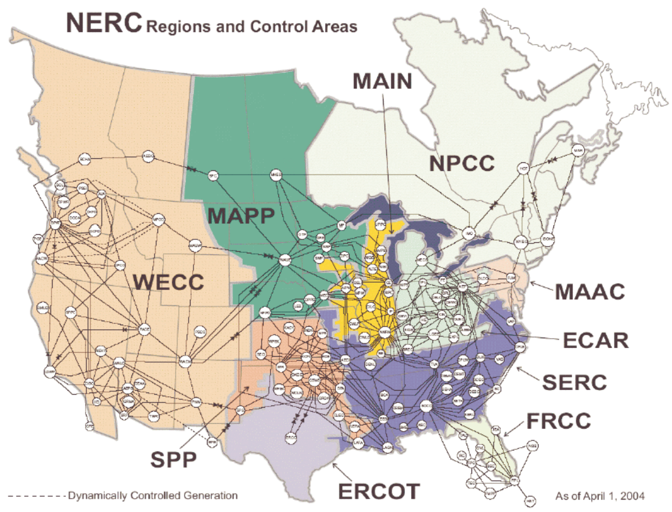


Figure 2 – NERC Regions and Control Areas
(obtained from NERC)

The Federal Energy Regulatory Commission (FERC) is an independent Federal agency that regulates the interstate transmission and sale of electricity (and natural gas and oil). However, neither FERC nor NERC currently regulates grid reliability. Under the current proposed Energy Bill, the electric industry will be self-regulated, and FERC will give NERC authority to require national conformance to the set of reliability standards.

The white circles in Figure 2 show the 130 control areas in the United States. Commonly called reliability transmission organizations (RTOs) or independent system operators (ISOs), these 130 control areas are the primary entities that operate the grid (and the power market in States that have deregulated the electric industry). As such, each control area (RTO or ISO) directs several operating companies. Before deregulation of the electric industry, the control areas were defined by the geographic boundaries that owned and operated the grid, and this is still true in some areas. Thus, there is significant diversity across the United States, and it is a complex task to coordinate this many companies and control areas to ensure reliable grid operation. To simplify matters, FERC has authorized the 130 control areas (RTOs and ISOs) to manage grid reliability and the electricity market in real time. As such, the control area operators' responsibility for grid reliability (as specified by NERC) includes the following key activities:

(1) **Balancing generation and demand.** At this point, it suffices to understand that power has two components: (1) real power (for resistive loads such as lights) that is measured in megawatts (MW) and (2) reactive power (for loads such as motors) that is measured in megavars (MVAR). To maintain system frequency, it is essential to balance the real power; the system frequency decreases when the generated MW level is less than the demanded MW level (and increases when the generated level is more than the demanded level). Conversely, to maintain system voltages, it is essential to balance the reactive power; the system voltage decreases when the generated MVAR level is less that the demanded MVAR level (and increases when the generated level is more than the demanded level). Other transmission system equipment (such as capacitor banks) helps to regulate the system voltages. In addition, to maintain the stability of system frequency and voltage, it is essential to have a sufficient "spinning" or operating MW and MVAR or take steps to maintain adequacy.

In the long-term, the control areas maintain adequacy by assessing the existing and planned availability of the generators to meet the demand. On a day-to-day basis they maintain adequacy by balancing generation and demand to meet frequency and voltage limits. When generation is insufficient, grid operators implement measures to increase generation, (such as voltage reductions, load shedding, or public appeals to voluntarily reduce load).

(2) **Maintaining transmission system operating reliability.** The control areas implement the results of the electric power market and maintain grid reliability. Toward that end, control areas operate so that instabilities, uncontrolled separations, or cascading outages will not occur as a result of severe single contingencies or multiple outages of a credible nature. Operating security (or reliability) limits include limits on transmission system transfer capability, as well as the thermal, voltage, and stability limits of the grid and load equipment. As such, they define the acceptable operating boundaries that must be maintained following a disturbance. Control areas have plans, policies, and procedures to operate the system such that it remains within acceptable operating limits. They also maintain parallel operations throughout the interconnection following a disturbance (such as a blackout or other contingency that results in a violation of operating security limits).

Following a disturbance, the grid operator for the affected control area is typically required to restore the transmission system to operating security limits within 30 minutes. In many cases, power recovery can take several hours or even a few days (depending on the extent of the problem, or the time to dispatch roving operators and mechanics to inspect and/or repair equipment). In the case of a large-scale grid event, the control area must first stabilize grid frequency (typically by connecting to a stable part of the grid that was unaffected by the disturbance), and then stabilize the voltage. In so doing, prompt return of power is essential in order to maintain transmission facility battery capabilities for power controls and equipment in the transmission and distribution systems. During the August 14, 2003 blackout, although power restoration to the NPPs was a priority, it took approximately 2.75 hours and 7.75 hours to stablize the frequency and voltage, respectively in New York.

(3) **Coordinating reliability.** NERC requires each control area to have a reliability coordinator (RC) who follows NERC procedures to analyze the current day operating conditions, plan the next day operations (including reliability analyses), and implement interconnection-wide procedures for handling transmission load relief (TLR) requests to mitigate transmission line overloads (also commonly called congestion).

Control areas must manage the congestion that results from generator open access to the transmission system and, as such, they are obligated to accept and implement power interchange transactions (transfers of energy within and between control areas) that take place in a market environment. NERC developed an Eastern Interconnection-wide TLR request procedure for the control area RCs to manage the anticipated congestion. The RCs can assign a TLR request at the appropriate level to direct the transmission provider to modify the transaction or operation to mitigate the congestion and ensure reliable grid operation. Appendix A, Table A-1, "Transmission Load Relief Request Summary," was reproduced from NERC information (Ref. 3) and shows RC actions and NERC comments by TLR request level.

(4) **Reporting Disturbances.** Control areas report grid disturbances and major electric utility system emergencies to DOE under Section 205.351, "Reporting Requirements," of Title 10, "Energy", Chapter II, "Department of Energy," Part 205, "Administrative Procedures and Sanctions," of the *Code of Federal Regulations* (Ref. 4). Specifically, 10 CFR 205.351 requires electric utilities or other entities engaged in the generation, transmission, or distribution of electric energy for delivery or sale to the public to report to DOE. Appendix A, Table A2, "Summary of DOE Reporting Requirements," lists the incidents and thresholds for grid events that must be reported to DOE. Control areas also report grid events to NERC under its program. Appendix A, Table A3, "Summary of NERC Reporting Requirements," lists the incidents and thresholds for grid events that must be reported to NERC (Ref. 3). NERC then studies the control area reports to identify any lessons learned from disturbances or unusual occurrences that jeopardize the operation of the interconnected system or identify vulnerabilities such as sabotage, blackouts above a threshold, and insufficient generation.

2.4 Recent Changes in Transmission System Loading

Increased transmission system loading is being driven by normal load growth, deregulation, and the lack of transmission projects. Pushing the system harder will result in more operation beyond limits, smaller margins for transmission system reliability, and a reduced system capability to withstand unexpected contingencies (Ref 2). As such, the grid requires much more management, control, and adjustment to keep the system within acceptable limits.

In 1992, the National Energy Policy Act (NEPA) encouraged competition in the electric power industry. Specifically, NEPA requires, in part, open generator access to the transmission system and statutory reforms to encourage the formation of wholesale generators. The electric industry began deregulating following the April 1996 issuance of FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities: Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," which requires that utility and non-utility generators must have open access to the electric power transmission system.

Open access transmission generally results in changes to grid design and operation that could challenge operating limits and grid reliability. Today, the power market results in more power transactions and transmission of electricity over longer distances, and grid operating entities that are not involved in the power transaction may see their operation affected by unexpected power flows. Regardless of their restructuring status or participation in the power market, all States and NPPs are exposed to design and operating challenges associated with the revised power flows attributable to open transmission line access.

The BOR states that with the absence of major transmission projects in the past 10–15 years, utilities have increased the utilization of the existing transmission facilities to meet increasing demands without adding major equipment. The BOR goes on to state that the system is being operated closer to the edge of reliability than it was a few years ago. The BOR predicts that "If nothing else changed, one could expect an increased frequency of large-scale event as compared to historical experience." Although NPP offsite power is typically supplied by two or more physically independent transmission lines, the blackout on August 14, 2003, demonstrates that the there is only one source of offsite power for several NPPs.

2.5 Recent Grid Events That Have Affected Nuclear Power Plant Performance

Transmission congestion near an NPP can cause degraded voltage conditions that adversely affect safety bus voltages. In addition, an increase in the frequency and duration of transmission line congestion potentially increases the risk from a degraded grid.

The results of grid analyses are typically summarized for an NPP in terms of the minimum and maximum expected voltages and impedances at the high-voltage terminals of the NPP power transformers. The magnituce of the transmission line loading near the NPP may adversely affect the NPP voltages. The NPP uses these grid parameters to calculate whether its internal voltages are within equipment ratings and the minimum voltages. Licensees periodically revise these analyses with updated external voltages and impedances from the grid operating entity. If the NPP internal voltages are not adequate (i.e., expecting that a unit trip or other condition would result in an operating voltage that is too close to the degraded voltage relay and alarm setpoint), the licensees and grid operating entities may adjust their systems (e.g., move the NPP or grid transformer voltage taps) or establish compensatory measures (e.g., procedure revisions) to avoid potentially adverse conditions or configurations. In some cases, the NPP or the grid operating entity may need to add equipment, such as a transformer with an automatic load tap changer or capacitors or other reactive supply. The following recent examples show how the grid has impacted the NPPs.

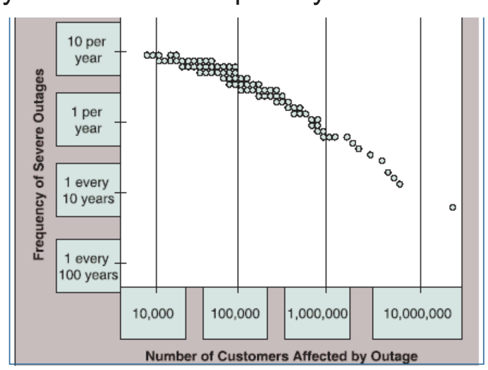
On August 11, 1999, the Callaway Plant's reactor was manually tripped from 100.78-percent power as a result of a ruptured feedwater drain line pipe. [See Licensee Event Report (LER) #483/99-003, "Manual Reactor Trip Due to Heater Drain System Pipe Rupture Caused by Flow-Accelerated Corrosion," dated August 11, 1999 (Ref. 5).] The next day, while at zero power, the Callaway switchyard voltage supplied from the grid decreased below the minimum operability level established in the station's procedures for 12 hours. [See LER #483/99-005, "Operating Conditions Exceeding Previously Analyzed Values Result in Inoperability of Both Offsite Power Sources," dated August 12, 1999 (Ref. 6).] The voltage drop resulted from near-peak levels of electric system loading and the transport of large amounts of power on the grid near Callaway, which were attributable to high summer temperatures. In this instance, it is clear that congestion near the plant degraded operating voltages. Related correspondence dated April 6, 2001 (Ref. 7), noted the licensee's statement that the deregulated wholesale power market contributes to conditions in which higher grid power flows are likely to occur (as in this case).

In its operating experience assessment concerning the effects of grid events on NPP performance (NUREG-1784, Ref. 1), the NRC staff provided some numerical measures to characterize grid performance before and after deregulation and, in particular, those related to a LOOP. In that report, the staff considered the period from 1985 through 1996 as being "before deregulation" and 1997 through 2001 "after deregulation." The assessment revealed that major LOOP-related changes since deregulation began include (1) a decrease in the frequency of LOOP events at NPPs; (2) an increase in the average duration of LOOP events and a substantial increase in the percentage of LOOPs lasting longer than 4 hours; (3) a predominance of LOOP events during the summer months (May–September), compared to a more or less random occurrence throughout the year before deregulation began; and (4) an increased probability of a LOOP as a consequence of a reactor trip during the summer months. In fact, the end of 2003 marked the seventh year in a row that LOOPs were dominated by grid-related or grid-initiated events that occurred in the summer, whereas LOOPs before deregulation were dominated by plant-centered events that occurred randomly throughout the year.

The blackout on August 14, 2003, was a cascading event that resulted in 9 reactor trips, 8 LOOPs, and minor transients at 70 other operating NPPs. That blackout and two other LOOPs in 2003 nearly doubled the amount of data that NUREG-1784 provided for the period after deregulation. While each NPP is connected to the grid by two or more physically independent transmission lines, the blackout on August 14, 2003, demonstrated that multiple NPPs share a single source of power. The blackout also demonstrated EDG reliability; in fact, with only one exception, all EDGs at all sites started and loaded, and the EDG that did not start was being tested to the grid, but separated and subsequently started.

2.6 Experts View the Grid as a Complex System

The BOR also discusses a major blackout that affected 50 million people and tripped 9 NPPs. Nonetheless, Chapter 7 of the BOR states that system-wide disturbances are rare, but occur more frequently than a normal distribution of probabilities would predict based on statistics adapted from Carson and Doyle's "Complexity and Robustness" (Ref. 8), as reproduced in Figure 3, "Blackouts in North America." Specifically, Carson and Doyle state that complex systems behave such that a small disturbance may dramatically alter the system to the point that it becomes chaotic because of the interplay between system components. Moreover, Carson and Doyle state that statistics of events in many complex interconnected systems share the common attribute that the distribution of sizes are described by power laws. Power laws are associated with straight-line slopes when plotted on log-log scale; that is, when the cumulative frequency and/or probabilities of events of greater than or equal to a given size are plotted on a log-log scale, the slope of the right hand side of the plot is a straight line (commonly referred to as a "power tail") and is clearly not exponential. Thus, because the curve depicted in Figure 3 has a power tail, it indicates that the grid is a complex system. Of interest to RES is that the BOR's statistical characterization of past blackouts differs significantly from the statistical representation of a LOOP (or a blackout, as discussed in Section 3.2.2 of this report) that the NRC staff uses in its probabilistic risk assessments.



Note: The circles represent individual outages in North America between 1984 and 1997, plotted against the frequency of outages of equal or greater size over that period.
Source: Adapted from John Doyle, California Institute of Technology, "Complexity and Robustness," 1999. Data from NERC.

Figure 3 – Blackouts in North America

Additional research revealed that the notion that the grid is a complex system has received a great deal of attention from experts in chaos theory and non-linear system dynamics. In fact, a team sponsored by DOE and the National Science Foundation (Carreras, Dobson, Newman and Poole) used NERC data to demonstrate that the grid is a complex system, as evidenced by multiple measures of blackout frequency and size that consistently show the power law behavior (Ref. 9)(Ref. 10). RES followup activities have resulted in a dialogue and information exchange with Carreras, an expert in chaos theory at Oak Ridge National Laboratory, starting in April 2004, that has enabled RES to verify and add to their base of research. (See Section 3.2.3 of this report.)

A recent article, entitled “The Unruly Power Grid,” dated August 2004 (Ref. 11), summarizes the work of Doyle, Carreras, and others. That article concludes that while these individuals have competing explanations of the mechanism behind the grid’s behavior, they agree on the statistics and that the notion that blackouts are a byproduct of the complex system and only a fundamental change in the system will cause a change in the grid’s behavior.

3. DISCUSSION

The RES staff is currently investigating grid operating data for indications of change or potential vulnerabilities that might otherwise be masked by investigating only the operating data for the NPPs themselves. Specific objectives are to obtain sufficient grid data to identify and assess the following considerations: (1) transmission system loading near NPPs; (2) grid reliability; (3) the percent of the time the grid is degraded such that a reactor trip will result in a LOOP; (4) whether the data indicate that the NPP offsite power supply is a complex system; and (5) vulnerabilities that are potential risk-significant issues for the NPPs.[3]

The NRC staff planned this assessment in three steps:

(1) As a first step, RES had to obtain reliable and representative grid data. Collaboration with the industry revealed that the NERC data set was best suited to our assessment. After discussing our plans with NERC and EEIB, RES decided to begin by investigating various aspects of grid reliability and transmission loading, which would then be summarized in a draft report for electrical engineering review by NERC and EEIB before RES proceeded with more detailed analyses.

(2) As a second step RES planned to identify and assess the variations in grid performance that have the potential to impact NPP performance or risk, and estimate the percentage of time during which the grid is degraded such that a reactor trip will result in a LOOP. As part of the second step, RES expected to obtain additional data and information through collaboration with the industry. To conclude this step, RES planned to document its findings in an interim report to solicit comments from appropriate internal and external stakeholders.

(3) The final step will involve developing a report that addresses the stakeholder comments on the interim report, and provides the basis for a Commission decision on whether the NRC should reevaluate the effectiveness of its existing electrical regulations (e.g., GDC 17) and other regulatory documents and protective features, as they relate to the sources of electrical power for NPPs. The results of this assessment will also indicate whether the NRC needs to validate the assumptions used in risk analyses of the reliability of the Nation's electrical power grid.

3.1 Data

In developing this report, the RES staff used two NERC databases to gather information for use in assessing whether the grid has experienced any change in reliability. Specifically, the staff drew upon the NERC Disturbance Analyses Working Group (DAWG) Database containing approximately 600 grid events from 1984 through 2003, and the NERC TLR request logs of approximately 7,000 records from 1997 through 2004 (Ref. 3).

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[3] Potential vulnerabilities are sensitive information that have been deleted from this version of the report.

3.2 Changes in Grid Performance and Potential Vulnerabilities

3.2.1 Changes in Transmission Loading

The RES staff used the NERC TLR request data to investigate transmission loading. As a next step, the staff will identify the TLR request numbers and durations that potentially impact the NPPs. The goal is to obtain sufficient data to enable the staff to assess the amount of time the grid is degraded near an NPP such that a reactor trip will result in a LOOP. Such information would provide valuable input for the NRC's future risk analyses.

Each TLR request contains the date, the name of the affected transmission line, the to-from flowgates (nodes in the transmission system network that define a specific transmission line), the TLR level, and the duration. NERC sorted and plotted the frequency data by year and month, and RES verified the frequency plots and sorted and plotted the TLR duration in the same manner. RES also completed time series plots of the TLR data by date and flowgate to depict the overload status of the grid.

Figure 4, "TLR Requests, 1997–2004," prepared by NERC (Ref. 3), shows the number of TLR requests in each month of every year from 1997 through the present. Specifically, Figure 4 shows the following changes:

- The number of TLR requests has increased each year since 1999 (i.e., the 1999 typically line bounds 1998, 2000 bounds 1999, and so forth).
- With the exception of February–April, the number of TLR requests during any given month in 1999–2004 is higher than the same month in the previous year.
- From 1999 through 2002, the number of TLR requests starts to ramp up in May, peak in August, and ramp down in October. The pattern changed in 2004, with a winter peak in January.

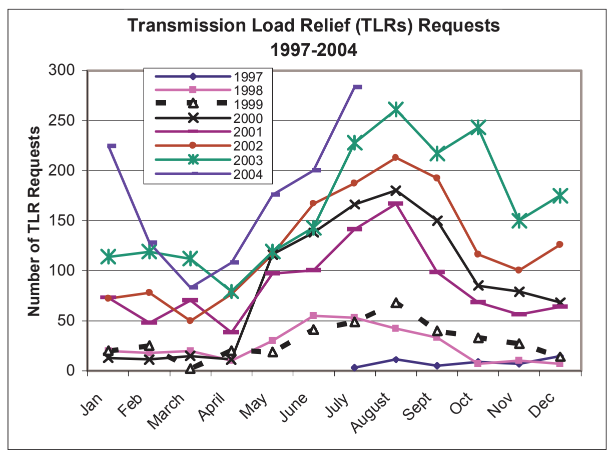

Figure 4 – TLR Requests, 1997–2004
(adapted from NERC)

- The number of TLR requests in 2004 increased over 2003, even though the summer of 2004 was mild in many parts of the country.

Figure 5, “Year-to-Year TLR Requests,” uses the same data as Figure 4 to draw a single time line depicting the increasing trend in the number of TLR requests from 1997 to the present. The trend is cyclic, with higher highs (except in 2001) and lows each year, and annual peaks in August.

Figure 6, “TLR Request Durations,” shows that the TLR durations follow the same increasing trend as the number of TLR requests, with the exception that July 2004 was not as bad as 2002 or 2003 (most likely because of the mild summer weather).

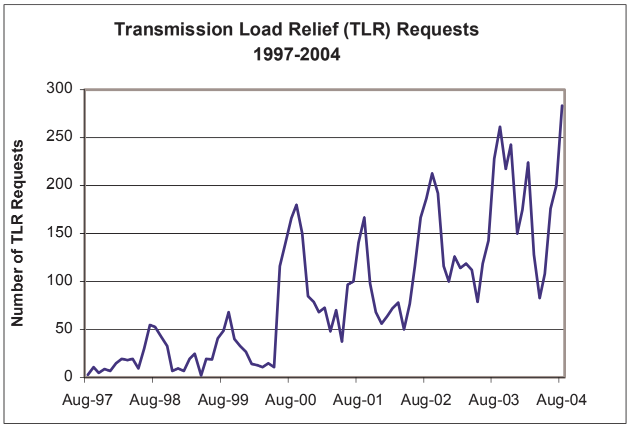

Figure 5 – Year-to-Year TLR Requests

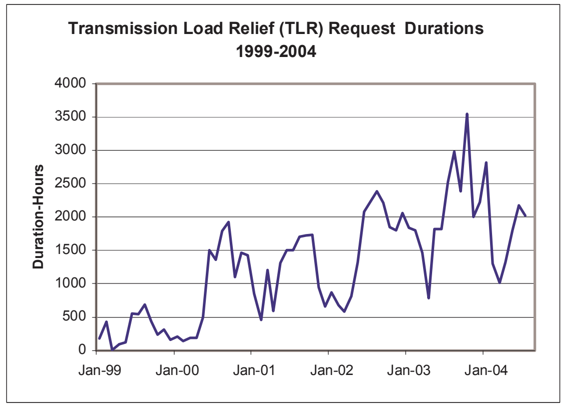

Figure 6 – Year-to-Year TLR Request Durations

Table 1, “TLR Request Hours at Levels 2–6, 1999–2003,” shows the number of hours accumulated each year at TLR request Levels 2–6. No data were available for 1997 and 1998. As previously explained, the TLR requests increase in importance as the level number increases. (The levels are explained in Appendix A, Table A-1) Table 1 shows that the duration at Levels 3–6 has increased, as shown by the year-to-year increases in the hours accumulated at each action level, with a decreasing number of hours accumulated below Level 3 since 2000 (zero in 2002 and 2003).

Table 1- TLR Request Hours at Levels 2–6, 1999-2003

	TLR Request Hours						
Level	2 a, b, c	3a	3b	4	5a	5b	TOTAL
Year							
1999	2598	1246*		89	5*		3937
2000	11380	3055	443	398	97		19015
2001	26	8397	1062	3963	1028	109	14505
2002	0	9274	2517	6630	210	45	18460
2003	0	12127	3484	10142	858	967	27578
* Final definition not available							

Figure 7, “TLR Request Durations”, charts the total TLR hours per day for 2001. The spikes indicate that the grid is degraded much more on some days (mostly in August–October), and the data show congestion on multiple transmission lines, indicating potential wide-area problems. In addition, Figure 8, “TLR Requests at Flowgates,” charts the total TLR hours per year at a flowgate. In this case, the spikes show that the TLR requests over the course of a year are worse at certain points on the transmission system (indicating bottlenecks). As a next step, the staff will develop charts similar to Figures 7 and 8 for each year since 1999. Identification of the TLR requests near an NPP could indicate the percentage of time during which the grid is degraded as a result of congestion; such information would prove useful in NPP risk analyses. (Locating the TLR conditions relative to a given NPP will require collaboration with NERC.)

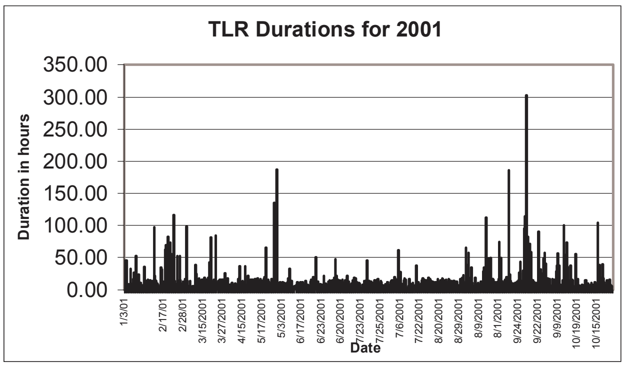

Figure 7 – TLR Request Durations for 2001

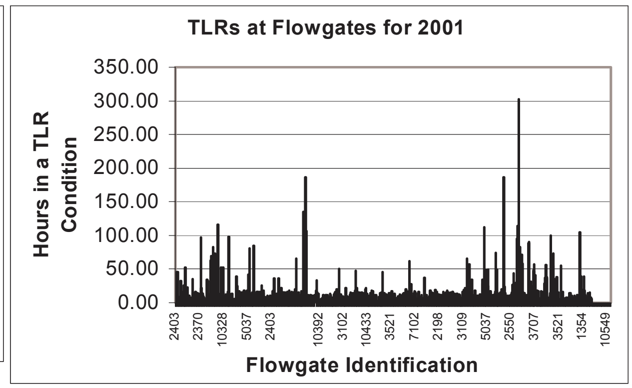

Figure 8 – TLR Requests at Flowgates

Based on the available data, one can observe that transmission system congestion (overloading) is increasing as a result of normal load growth, open generator access to the transmission system because of deregulation of the electric industry, and limited transmission system construction over the past 15–20 years. NERC anticipated transmission line congestion and created the TLR request procedure to manage the problem. However, the TLR request logs show that the transmission system has become increasingly congested each year from 1999 through 2004. The data may also indicate potential bottlenecks or problem areas; the data also show that the transmission system is more congested at some times than at others and more congested on some days than on others (mostly from August through October). Experience shows that transmission line congestion near an NPP degrades the plant’s operating voltages and may result in a LOOP in the event of a reactor trip. As a next step, it appears that sufficient data are now available to determine the percentage of time during which the grid is in a degraded condition under which an NPP reactor trip will result in a LOOP.

3.2.2 Changes in Grid Reliability

NERC DAWG maintains database of the events that are reported to DOE and NERC, and each DAWG record typically contains the date and time of the event, the affected NERC region and control area or operating entity, and a brief description of the event. In addition, the DAWG records may contain the time required to restore service to all or a large percentage of the customers, the cause of the event, the lost amount of generation, the lost amount of load, and/or the number of lost customers. For the purpose of this analysis, the RES staff first sorted the DAWG database records by date. In a few cases, multiple entities reported events with the same date and time, and the staff counted these as a single event.

This study summarized the frequency of the DAWG data for 1984–2003 in 5-year increments because the annual data showed too much variability to be informative; the use of 5-year increments smoothed the data. The DAWG records analyzed in this study used NERC's grid reliability definitions to bin the events into the following four categories:

(1) **Adequacy events**. 193 events involved insufficient generation to meet demand. For the purposes of this study, this category included incidents involving area voltage reductions, public appeals, and load shedding to balance demand with generation (as shown in Table A-1).

(2) **Security or operating system reliability events**. The 445 events in this category show the grid's ability to cope with contingencies including weather- and non-weather-related blackouts. The DAWG records of these 445 events included some combination of the following data:

- power recovery time to most of the customers that were involved in the blackout (approximately 350 data points)
- uncontrolled loss of firm load of more than 300 MW for 15 minutes or more or load shedding of 100 MW or more to balance demand with generation following a system disturbance (approximately 380 data points)
- loss of electric service to 50,000 customers for more than 1 hour (approximately 320 data points)
-

Blackouts on the order of 300 MW typically represent a small percentage of most operating company loads, so the system should be able to withstand the blackout contingency. Some of the events also had data for the amount of generation loss (about 100 data points) and initial recovery time (about 30 data points), which will be addressed in the second phase of this assessment.

To the grid, an NPP LOOP is a blackout that results from the loss of one large customer from the grid (typically 50–60 MW of house and safety bus loads); however, an NPP LOOP does not reach the DOE/NERC reporting threshold of a loss of >300 MW. The frequency and duration of some grid events is known to impact both NPP LOOP and SBO risks. Accordingly, RES had particular interest in the frequency and size, and particularly the duration, of the NERC blackout events. The assessment used the DAWG data to summarize the frequency and probability distribution function of the measures of blackout size and compared it to similar plots of NPP LOOP data. This assessment also verified and expanded upon the work of Carreras et al., which used the DAWG data to show that the grid is a complex system.

(3) **Unusual events**. The DAWG database included approximately 68 events that were reported to DOE/NERC as unusual occurrences and identify potential vulnerabilities for grid adequacy or operating reliability. Typically, events of this type had not yet affected an NPP; however they are potential vulnerabilities for NPP risk and physical security.

(4) **Events of no interest** that did not appear to fall into any of the above three categories.

Figure 9, “Operating Reliability Trends,” charts NERC operating reliability data using blackouts in the DAWG database for 1984–2003. The operating reliability trend was divided into weather-related blackouts (ice storms, hurricanes, lightning storms, tornados, and wind) and non-weather-related blackouts. Figure 9 shows that the grid was less reliable in 1999–2003 than it was in the previous 15 years. Figure 9 also shows that the number of blackouts has doubled, increasing from approximately 100 blackouts in each 5-year period from 1984 through 1999 to 200 blackouts in the 5-year period from 1999 through 2003. The proportion of weather-related events to non-weather-related events is essentially constant across the time intervals studied. As a next step, RES will identify the non-weather-related causes of blackouts.

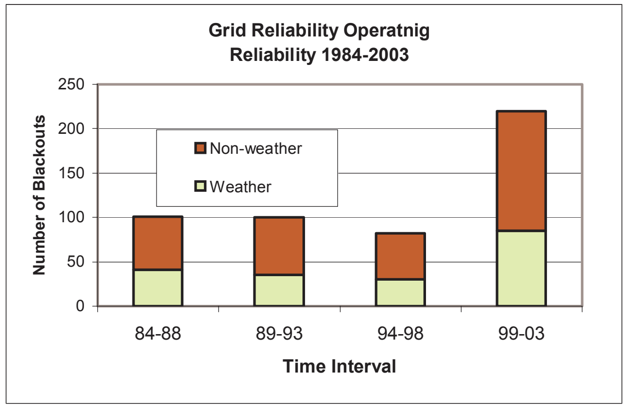

Figure 9 - Operating Reliability Trends

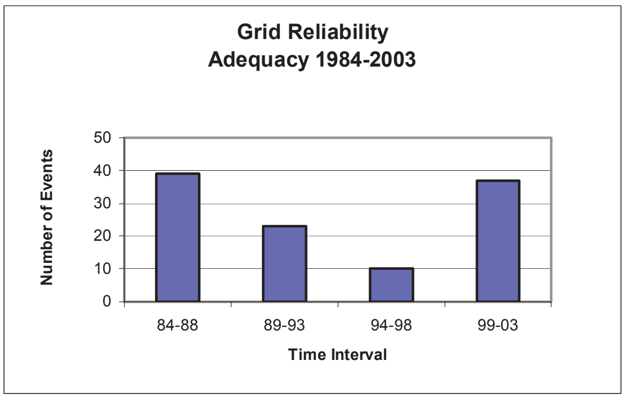

Figure 10 – Adequacy Trends

Figure 10, “Adequacy Trends,” charts the NERC adequacy data using the number of insufficient generation events in the DAWG database for 1984–2003. Figure 10 shows that the decreasing trend in the number of adequacy events in 1994–1998 has been offset by the increase in 1999–2003. (The number of adequacy events decreased from approximately 40 in 1984–1988 to 10 in 1994–1998, but increased to 38 in 1999–2003.)

Figure 11, “Median Load Loss in a Blackout,” and Figure 12, “Median Blackout Recovery Time,” show that an increasing trend in the combined (weather- and non-weather-related) median size and median duration of blackouts, and this increase is dominated by weather-related events. Figure 11 shows that the combined median of the customer load loss in a blackout has increased by 19 percent from 332 MW in 1984–1988 to 395 MW in 1999–2003. However, the median for weather-related events has nearly doubled from 241 MW in 1984–1988 to 480 MW in 1999–2003, while the median load loss for non-weather related events has remained relatively constant.

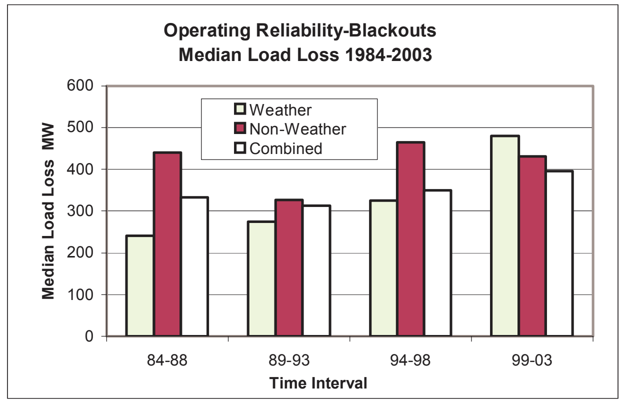

Figure 11 – Median Load Loss in a Blackout

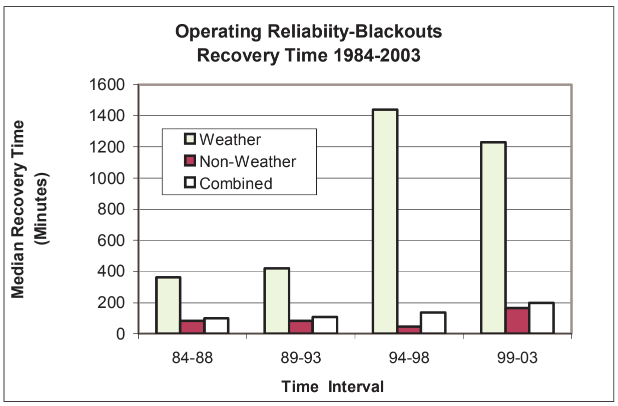

Figure 12-Median Blackout Recovery Time

Figure 12 shows that the combined median time to recover power to most customers following a blackout has nearly doubled from 101 minutes in 1984–1988 to 200 minutes in 1999–2003. However, the median for weather-related events has increased by a factor of 3.4 from 362 minutes in 1984–1988 to 1,230 minutes in 1999–2003, and the median time to restore power has doubled from 83 to 166 minutes in the same time intervals after peaking in 1994–1998.

Figure 13, "Blackouts With Load Loss >800 MW," and Figure 14, "Blackouts With Recovery Time >4 Hours," show that since 1999, the largest blackouts (with a load loss greater than 800 MW and last more than 4 hours) are both larger and of longer duration than those that occurred in 1984–1998. Figure 13 shows that the number of blackouts with a load loss greater than 800 MW has nearly doubled from 20 in 1984–1988 to 38 in 1999–2003, and the increase is dominated by non-weather-related blackouts, which increased from 15 in 1984–1988 to 24 in 1999–2003. Similarly, Figure 14 shows that the number of blackouts that took more than 4 hours to recover power to most customers has tripled from 22 in 1984–1988 to 66 in 1999–2003. In this case, the number of non-weather-related blackouts has increased from 8 in 1984–1988 to 28 in 1999–2003, while the number of weather-related blackouts has increased from14 in 1984–1988 to 38 in 1999–2003.

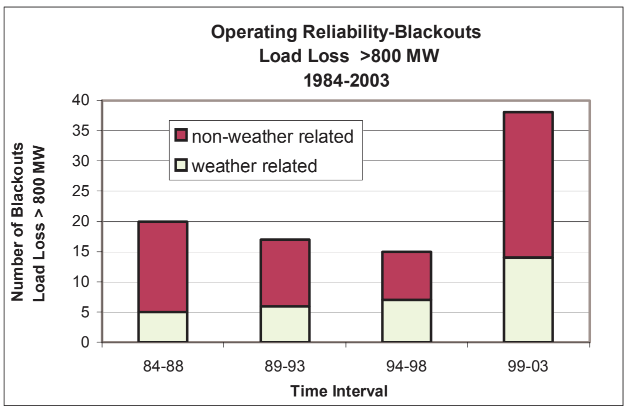

Figure 13 – Blackouts with Load Loss >800 Megawatts (MW)

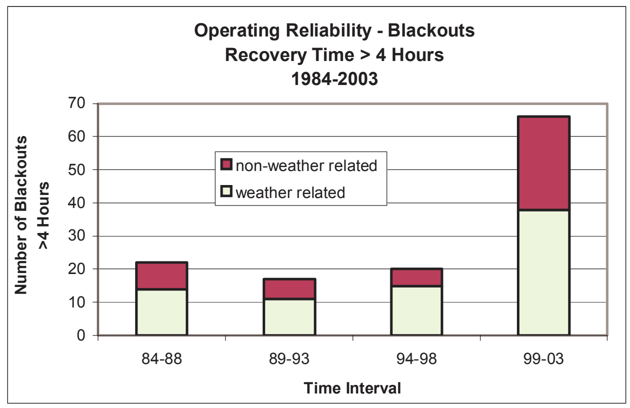

Figure 14 – Blackouts with Recovery Time >4 Hours

Based on the available NERC data, one can observe that the grid has experienced changes in reliability. The adequacy improvement over the 15-year period from 1984 through 1998 has been offset by the decline in grid performance from 1999 through 2003. Operating reliability was also lower in 1999–2003 than it was in the preceding 15 years. Specifically, since 1999, the number, median size, and median duration of the blackouts has increased, and the largest blackouts (those that are larger than 800 MW and last more than 4 hours) are both larger and of longer duration than the largest blackouts that occurred before 1999. It appears that pushing the transmission system harder has diminished the grid's capability to withstand contingencies. In addition, the NRC's current risk assessments (which typically average NPP LOOP data from the past 15–20 years) may mask vital information; the data since 1999 may reflect true grid performance and challenge the NRC assumptions that use grid data before 1999.

Figures 15, "Seasonal Effects On Operating Reliability," and Figure 16, "Seasonal Effects On Adequacy," show how summertime operation (May–September) affects grid adequacy and operating reliability compared to the other months of the year. Specifically, these figures show that historically, more operating reliability events have occurred in the "other" months, while more adequacy events have occurred in the summer months. The data indicate that one must be cognizant of the potential for grid degradation throughout the year.

Figure 17,"Blackouts by Interconnection," and Figure 18, "Adequacy by Interconnection,"

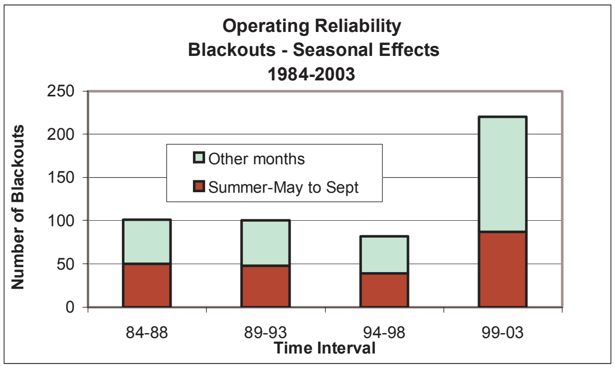

Figure 15 – Seasonal Effects On Operating Reliability

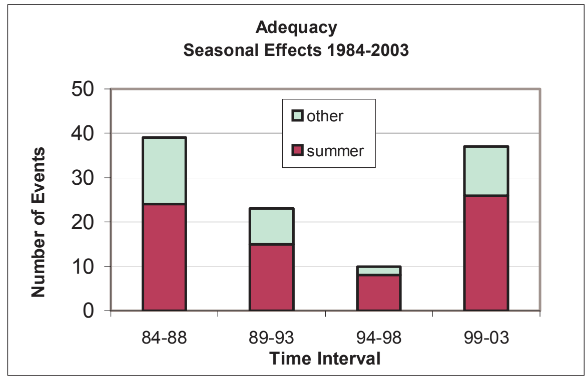

Figure 16 – Seasonal Effects On Adequacy

show trends in adequacy and operating reliability events by interconnection. Specifically, these figures show that historically, most adequacy and operating reliability events have occurred in the Eastern Interconnection and this has not changed. Figure 17 shows that in 1999–2003, the number of blackouts increased by factors of 2 in the Eastern Interconnection and a factor of 1.5 in the Western Interconnection. In addition, a few events occurred in the Texas Interconnection, which had not experienced blackouts in the preceding 15 years. By contrast, Figure 18 shows that the decreasing trend in adequacy-related events in the Eastern Interconnection in 1984–1998 has been offset by the increase in 1999–2003.

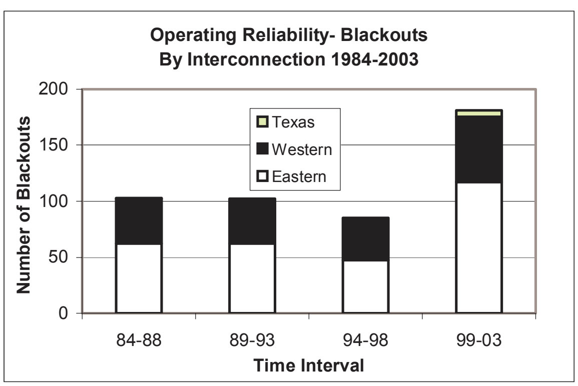

Figure 17 – Blackouts By Interconnection

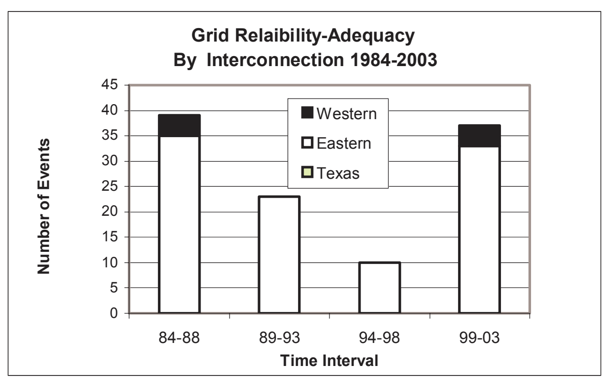

Figure 18 – Adequacy By interconnection

Based on the available data, one can make the following observations:

- *Historically, most events affecting grid reliability have occurred in the Eastern Interconnection.*
- *Most adequacy-related events take place in the summer months (May–September).*
- *Most operating security events take place in non-summer months (October–April).*
- *The decreasing trend in adequacy-related events in the Eastern Interconnection in 1984–1998 has been offset by the increase in 1999–2003.*

These observations suggest that one must be cognizant of the potential for grid degradation at any place and any time throughout the year.

3.2.3 Characterizing NPP Offsite Power As Complex System

Experts in chaos theory and non-linear system dynamics have found that the grid is a complex system (Ref 8, 9, 10, 11), as it can operate in a condition where a small event has widespread effects; mathematically, the presence of a "power tail" (as opposed to an "exponential tail") in the probability distribution of blackout size confirms the nature of the grid as a complex system. The BOR used one expert's work (Doyle) to develop its statistics, and RES collaboration with another expert (Carreras) as a second expert opinion. Carreras suggested that as a starting point, that we plot the actual data as a probability distribution with a log-log scale of the number of NERC blackouts of more than "N" duration to recovery, load loss, and customer loss against "N" to show a cumulative frequency function. This plot is complementary to the probability function shown in Carreras' et al papers, in which he grouped the data in bins rather than plotting the actual values. The results are shown in Figure 19, "Blackout Frequency and Duration"; Figure 20, "Blackout Frequency and Load Loss"; and Figure 21, "Blackout Frequency and Customers Lost." Omitting the blackout on August 14, 2003, did not change the results.

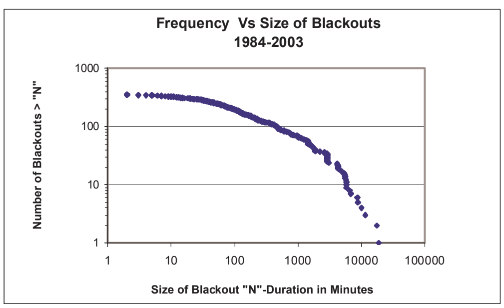

Figure 19 – Blackout Frequency and Duration

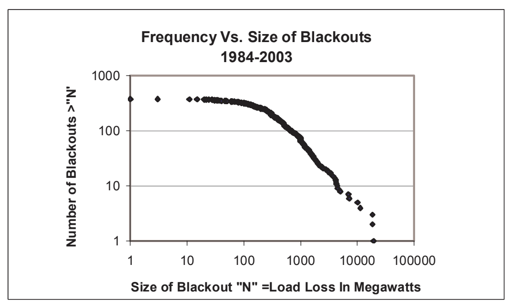

Figure 20 – Blackout Frequency and Load Loss

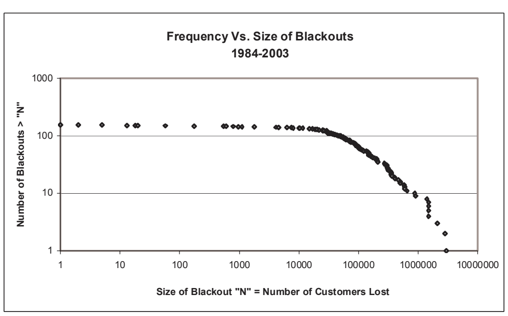

Figure 21 – Blackout Frequency and Customers Lost

The staff also investigated the NPP LOOP data for the presence of a power tail. Figure 22, "NPP LOOP and NERC Blackout Frequency and Duration," shows separate curves for the NPP LOOP and NERC blackout data. Comparison of the two plots shows that the NPP data have a more pronounced power tail than the NERC blackout data, indicating that the NPP offsite power system is a complex system.

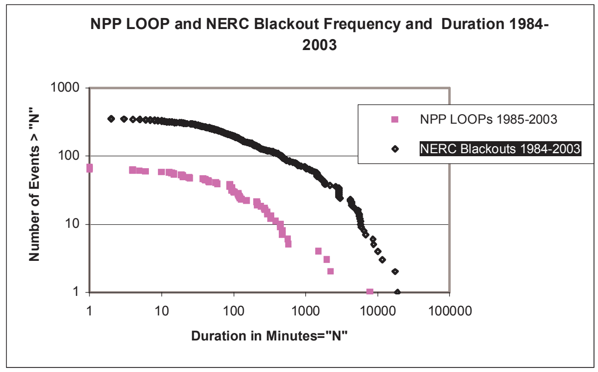

Figure 22 – NPP LOOP and NERC Blackout Frequency and Duration

Figure 23, "NPP LOOP and NERC Blackout Frequency and Duration Combined," is a single, combined plot of the NPP LOOP and NERC blackout data. It makes sense that it would all be the same data since a LOOP is a blackout (i.e., the loss of 60 MW of NPP auxiliary load from the grid). However, an NPP LOOP does reach the DOE/NERC reporting threshold of a loss of >300 MW.

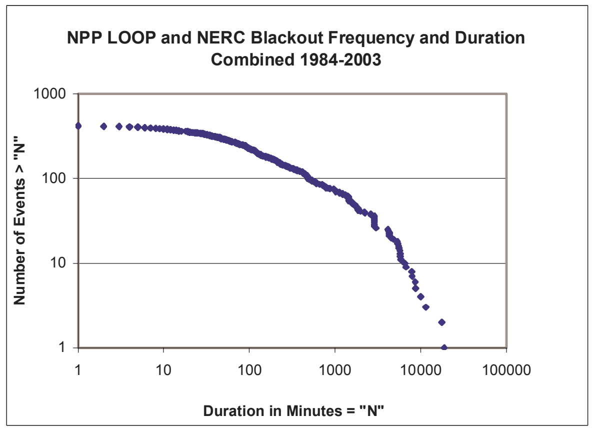

Figure 23 – NPP LOOP and NERC Blackout Frequency and Duration Combined

The NRC does not currently treat the NPP offsite power as a complex system. The application of complex system theory requires different methods than the NRC uses, and may yield different results and risk insights than the traditional NRC approach, as illustrated by the following examples:

(1) From a grid perspective all LOOPs are blackouts. The size of the LOOP blackout, rather than the NRC cause classification (plant, weather, grid), may be a more informative characterization of LOOPs for probabilistic analyses. Using complex theory statistical methods, the experts found that weather-related blackouts do not show any properties that distinguish them from other blackouts (Ref 9, 10), and this finding differs from the NRC's conclusions, which provide separate statistics for weather-related LOOPs.

(2) The fundamental assumption in the NRC's statistical and risk analyses is that events are independent (i.e. in the case of the grid, events are localized such that a single grid event affects one — and only one — NPP). During the blackout on August 14, 2003, however, a single initiator resulted in 9 cascading reactor trips, 8 LOOPs, and minor/moderate transients at 70 other plants. Also there have been multiple unit reactor trips as a result of a single grid initiator. In addition, the NRC traditionally considers the NPP offsite power system as a simple system for which the analyses estimate individual NPP risks, rather than a single complex system for which the risk is the sum of all individual NPP risks. In practice, however, the blackout on August 14, 2003, demonstrated that NPP offsite power sources may not always be electrically independent.

(3) The blackout on August 14, 2003, and other large blackouts are not isolated cases; rather, they are predictable using the log-log plots of historical blackout frequency and duration.

(4) The complex system experts views show that a cascading event in unavoidable when the grid is operated near a critic point (Ref. 10); i.e., any one of a number of initiators will trigger the event when operated near a critical point. When the event occurs, corrective actions to keep the event from reoccurring naturally address the trigger. However, as NPP risks from multiple unit reactor trips as a result of a single grid initiator are additive, it is essential that corrective actions focus that prevent cascading events. For example, in addressing the corrective actions from the August 14, 2003 blackout, actions to require that grid operation to conform to NERC reliability standards to operate the grid away from critic points will prevent cascading events; fixing the initiator (tree trimming) will prevent further individual transmission line faults.

Based on the available data, this assessment supports the findings of experts in chaos theory and non-linear system dynamics, which indicate that the grid is a complex system. Complex systems behave such that a small disturbance alters the system to the point of chaos because of the interplay between the system components. The characteristic curve of a complex system is described by power laws (i.e., a straight line slope, commonly referred to as a power tail) when the cumulative frequency (or probabilities) of blackout size is equal to or greater than a given size when plotted on a log-log scale. By contrast, simple systems would have an "exponential tail" in the log-log probability distribution of blackout size. The experts showed that the grid data have a power tail. Moreover, the NPP LOOP data yield a more pronounced power tail than the grid data, indicating that the NPP offsite power system tends to be a complex system. This is significant because the methods used to describe complex systems differ from those that the NRC currently uses to assess NPP risks relative to grid performance and, consequently, application of complex system techniques may yield different results and risk insights.

4.0 ASSESSMENT TO DATE

This assessment of grid reliability based on performance trends developed from the NERC data, including 600 grid events from 1984 through 2003 and 7,000 TLR request records from 1997 through 2004. In so doing, the staff classified the 600 grid events to the NERC definition for adequacy, operating reliability, or unusual events. The staff then used the data to provide reliability measures to gauge recent changes in grid operation. An assessment (such as this) that is based on a large amount of data should promote confidence in the results. The results obtained to date indicate changes and vulnerabilities that have the potential to adversely impact NPP voltages and risks. In fact, since 1999, transmission system congestion has increased and the Nation has experienced an increased number of larger and longer-lasting grid blackouts than the previous 15 years. In addition, results obtained to date indicate that both the grid and the NPPs' offsite power supply are complex systems, and grid-related events created conditions in which power took a long time to restore. To elaborate on the most notable observations obtained to date:

(1) Transmission system congestion (overloading) is increasing as a result of normal load growth, open generator access to the transmission system as a result of deregulation of the electric industry, and limited transmission system construction over the past 15–20 years. NERC anticipated transmission line congestion and created a TLR request procedure to manage the congestion. The TLR request logs show that the transmission system has become increasingly congested each year from 1999 through 2004. The data also show that the transmission system is more congested at some times than at others and more congested on some days than on others (mostly from August through October). The data may also indicate potential bottlenecks or problem areas. Experience shows that transmission line congestion near an NPP degrades the plant's operating voltages and may result in a LOOP in the event of a reactor trip. As a next step, it appears that sufficient data are now available to determine the percentage of time during which the grid is in a degraded condition under which an NPP reactor trip will result in a LOOP.

(2) The NERC data indicate changes in grid reliability. Adequacy improvement over the 15 years prior to 1999 has been offset by the decline in grid performance from 1999 through 2003. Operating reliability was less from 1999 through 2003 than it was in the preceding 15 years. Specifically, since 1999, the number, median size, and median duration of blackouts have increased, and the largest blackouts (those that are larger than 800 megawatts and last more than 4 hours) are both larger and of longer duration than the largest blackouts that occurred before 1999. Thus, it appears that pushing the transmission system harder has diminished the grid's capability to withstand contingencies. In addition, the NRC's current risk assessments (which typically average NPP LOOP data from the past 15–20 years) may mask vital information; the data since 1999 may reflect true grid performance and challenge the NRC assumptions that use grid data before 1999.

(3) This assessment supports the results of experts in chaos theory and non-linear system dynamics, which indicate that the grid is a complex system. Complex systems behave such that a small disturbance alters the system to the point of chaos because of the interplay between the system components. The characteristic curve of a complex system is described by power laws (i.e., a straight line slope, commonly referred to as a power tail) when the cumulative frequency (or probabilities) of blackout size is equal to or greater than a given size when plotted on a log-log scale. By contrast, simple systems would have an "exponential tail" in the log-log probability distribution of blackout size. The experts showed that the grid data have a power tail. Moreover, the NPP LOOP data yield a more pronounced power tail than the grid data, indicating that the NPP offsite power system tends to be a complex system. This is significant because the methods used to describe complex systems differ from those that the NRC currently uses to assess NPP risks relative to grid performance and, consequently, application of complex system techniques may yield different results and risk insights.

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As a next step, the RES staff plans to obtain electrical engineering comments, continue to analyze grid data, and issue an interim report for internal and appropriate stakeholder review.
As RES moves forward, these findings may require the NRC staff to reevaluate the effectiveness of its existing regulatory documents and protective features (as they relate to the sources of electrical power for NPPs), and/or revisit the assumptions used in risk analyses of the reliability of the Nation's electrical power grid.

APPENDIX A

GRID EVENT REPORTING REQUIREMENTS

AND TRANSMISSION LOAD RELIEF REQUEST SUMMARY

Table A1 - NERC Transmission Load Relief Request Summary

TLR Level	Reliability Coordinator Action	Comments
1	**Notify** RELIABILITY COORDINATORS of potential OPERATING SECURITY LIMIT violations.	
2	**Hold** INTERCHANGE TRANSACTIONS at current levels to prevent OPERATING SECURITY LIMIT violations.	Of those transactions at or above the CURTAILMENT THRESHOLD, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm POINT-to POINT Transmission Service are not held.
3a	**Curtail** Reallocation Transactions using Non-Firm POINT-to-POINT Transmission Service to allow Transactions using higher priority POINT-to-POINT Transmission Service.	Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the REALLOCATION process.
3b	**Curtail** Transactions using Non-Firm POINT-to-POINT Transmission Service to mitigate Operating Security Limit Violations.	Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm POINT-to-POINT Transmission Service.
4	**Reconfigure** transmission system to allow Transactions using Firm POINT-to-POINT Transmission Service to continue.	There may or may not be an OPERATING SECURITY LIMIT violation. There are special considerations for handling Transactions using Firm POINT-to-POINT Transmission Service.
5a	**Curtail** Reallocation Transactions using Firm POINT-to-POINT Transmission Service (pro rata) to allow new Transactions using Firm POINT-to-POINT Transmission Service	Attempt to accommodate all Transactions using Firm POINT-to-POINT Transmission Service, but at a reduced (pro rata) level. Pro Forma tariff also requires curtailment/REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load.
5b	**Curtail** Transactions using Non-Firm POINT-to-POINT Transmission Service to mitigate Operating Security Limit Violation	Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load.
6	**Emergency Action**	Could include demand-side management, redispatch, voltage reductions, interruptible and firm load shedding.
0	**TLR Concluded**	**Restore** transactions.

Clarifications:

Level 1 provides for an alert to notify the market and other RCs that interchange curtailment (of the megawatts being transmitted over the constrained transmission line/equipment) is likely to occur.

Level 2 indicates a operating security limit is about to occur. If it lasts more than 30 minutes, it is upgraded to Level 3a.

Level 3a allows the RC to reallocate transmission service to give priority to its own transactions and those having the greatest economic benefits (firm point to point transactions) by planning to curtail others transactions (non-firm point to point transactions) first; otherwise, the situation would cause an operating security limit violation.

Level 3b indicates curtailment has taken place.

Level 4 indicates the control area has been requested to reconfigure the system so the interchange transactions can continue before proceeding to Level 5a.

Level 5a requires the RC to reallocate firm point-to-point transactions.

Level 5b indicates the curtailment has taken place. If curtailment does not mitigate the constraint, the TLR request is upgraded to a Level 6.

Level 6 gives the RC the authority to immediately direct the control areas to take actions until the critical condition is mitigated.

Table A2- Summary of DOE Reporting Requirements

DOE Reporting Requirements		
Incident	**Threshold**	**RES Analysis Category**
Uncontrolled loss of firm system load	$300MW for 15 minutes or more	Operational reliability
Load shedding	$100 MW under emergency operational policy	Adequacy
Voltage reductions	3% or more (applied system-wide)	Adequacy
Public appeals	Emergency conditions to reduce demand	Adequacy
Physical sabotage, terrorism or vandalism	On physical security systems (suspected or real)	Unusual event
Cyber-sabotage, terrorism, or vandalism	If attempt is believed to have happened or did happen	Unusual event
Fuel supply emergencies	Fuel inventory or hydro storage levels #50% of normal	Unusual event
Loss of electric service	$50,000 for 1 hour or more	Operational reliability
Complete operational failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	Unusual event

Table A3 - NERC Reporting Requirements

Incident	Threshold
Loss of major component	Significantly affects integrity of interconnected system operations
Interconnected system separation or system islanding	Total system shutdown, partial shutdown, separation, or islanding
Loss of generation	$2,000 MW (Eastern Interconnection) $2,000 MW (Western Interconnection) $1,000 MW (Texas Interconnection)
Loss of firm load $15 minutes	300 MW for entities with peak demand $3,000 MW All others $200 MW or 50% of total demand.
Firm load shedding	$100 MW to maintain continuity of bulk system
System operation or operation actions	• voltage excursions $10% • major damage to the system • failure, degradation of mis-operation of the protective system
Operating security (operating system reliability) limit violation	Policy 2A, "Transmission Operations," Standard 2.1
As requested	Due the nature of disturbance and usefulness to industry (Lessons Learned)

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2. U.S.-Canadian Power System Outage Task Force, “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,” April 5, 2004.

3. This information can be downloaded from the North American Electric Reliability Council Web site, www.nerc.com.

4. *Code of Federal Regulations*, Title 10, “Energy”, Chapter II, “Department of Energy,” Part 205, “Administrative Procedures and Sanctions,” Section 205.351, “Reporting Requirements,” for Major Electric Utility System Emergencies.

5. U.S. Nuclear Regulatory Commission, Licensee Event Report (LER) #483/99-003, “Manual Reactor Trip Due to Heater Drain System Pipe Rupture Caused by Flow-Accelerated Corrosion,” August 11, 1999.

6. U.S. Nuclear Regulatory Commission, Licensee Event Report (LER) 483/99-005, “Operating Conditions Exceeding Previously Analyzed Values Result in Inoperability of Both Offsite Power Sources,” August 12, 1999.

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9. B.A. Carreras, D.E. Newman, I. Dobson, and A.B. Poole, “Initial Evidence for Self-Organized Criticality in Electric Power System Blackouts,” *Thirty-Third Hawaii International Conference on System Sciences*, Maui, Hawaii, January 2000.

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